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Energy Consulting Inc. Gas-fired Cogeneration Plant in Stettler

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Energy Consulting Inc.
Gas-fired Cogeneration Plant in Stettler

ENERGY RESOURCES CONSERVATION BOARD

Report D 93-2

Application No. 910097 by Energy Consulting Inc., for approval to construct a 25-MW gas-fired power plant in Stettler and connect it to the electric system of Alberta Power Limited.

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ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

ENERGY CONSULTING INC.
GAS-FIRED COGENERATION PLANT
IN STETTLER

Decision D 93-2
Application No. 910097

1 APPLICATION AND HEARING

1.1 Application

Energy Consulting Inc. (ECI), on behalf of itself and the Town of Settler (the Town), filed Application No. 910097 under sections 9 and 17 of the Hydro and Electric Energy (HEE) Act requesting that the Energy Resources Conservation Board (ERCB or the Board):

(a) approve construction of a 25-megawatt (MW) gas-fired power plant in Stettler,

(b) approve connection of the power plant to the electric system of Alberta Power Limited (Alberta Power),

(c) establish a basis for determining the value of the output from the power plant using the rates prescribed by the Small Power Research and Development Program (the Program), and

(d) issue an order requiring Alberta Power to purchase the plant output from ECI for a period of 20 years.

In the event that the ERCB determined the plant was not needed at this time, ECI requested that the ERCB allot to it the next 25 MW of generating capacity required by the Alberta Interconnected System (AIS) and establish when the plant output will be required by the AIS.

The overall development, identified as the Stettler Cogeneration/Greenhouse Project, would be located in the Town of Stettler and would include:

(a) a power plant consisting of a 25-MW gas-fired combustion turbine and steam generating facilities,

(b) a 30-acre greenhouse complex supplied with steam and electricity from the power plant, and

(c) a transmission line to connect the plant to Alberta Power's electric system.

The power plant would have a nominal capacity of 25 MW. The main fuel for the power plant would be natural gas from wells or gas pipelines in the area. The proposal is not eligible for consideration under the Program.

The applicant, following requests for additional information from the ERCB and the Department of the Environment, filed supplementary information in August 1991 and February 1992. The ERCB completed its review of the application and supplementary information and issued a notice of hearing in May, 1992.

1.2 Hearing

The application was considered at a hearing in Stettler from 11-13 August 1992, with Board Members J. P. Prince, Ph.D. (Chairman), R. G. Evans, P.Eng., and A. C. Barfett, Acting Board Member, sitting. In the event that the application were to be approved, the matter of determining value of plant output might have to be considered by the Public Utilities Board (PUB). Therefore, the Board invited the Acting Chairman of the PUB, A.C. Barfett, to sit as an Acting Board Member of the hearing panel. Those who appeared at the hearing are listed in Table 1. The City of Calgary and the City of Edmonton (Edmonton Power) were present at the hearing for purposes of cross examination and argument. The City of Lethbridge, the City of Red Deer, the Village of Forestburg, and L. F. Rosquist filed written submissions but were not represented at the hearing.

2 BACKGROUND

The electric industry in Alberta is regulated by the ERCB and PUB. The ERCB is responsible for, among other things, orderly and efficient development of oil, gas, oil sands, coal, and electric energy resources in Alberta. The PUB is responsible for, among other things, establishing rates for services provided by utility companies.

Construction and operation of any power plant which will be connected to the AIS must be approved by the ERCB. The ERCB also has authority to order the connection of a power plant to an electric system. With respect to the transfer of energy between the power plant and the electric system, the ERCB may also order when or within what time and on what terms and conditions, except as to amount of payment of compensation.

The PUB has authority to determine the amount of compensation paid for the sale of energy from a power plant to an electric system. The PUB also has authority, through setting of rates, to allow utilities to charge their customers in order to recover costs of facilities built to generate, transmit, and distribute electric energy.

Typically, a utility company or developer applies to the ERCB for approval to construct a plant. In most cases, the ERCB reviews the capability of the existing power system (including projected plant retirements) and current forecasts of demand for electricity to determine the need for and timing of new facility additions. It then assesses whether approval of the applied-for facility would be consistent with economic, orderly, and efficient development of the electric system in Alberta.

PUB involvement normally takes place after the facility is approved and constructed. Typically, a regulated utility would apply to the PUB to obtain compensation for the costs incurred in building and operating the power plant. In the case of a private developer, the contract between the utility company and the developer may be filed with the PUB for approval. If agreement as to amount of compensation cannot be reached the PUB may be asked to decide the matter.

Several electric utilities operate in Alberta, each providing electric service in different areas of the province. Their geographic location, combined with the generation mix and location of major load centers, creates disparity in the cost of electric service between utilities. In 1982, the Electric Energy Marketing Act was proclaimed and the Electric Energy Marketing Agency (EEMA) was created to bring about a measure of equalization in electric energy costs in various regions of the province. EEMA, pursuant to PUB orders, purchases all electric energy produced by TransAlta Utilities

Corporation (TransAlta), Alberta Power, and Edmonton Power. The energy is purchased at a price that reflects the utilities' generation and transmission costs. EEMA pools these costs and sells the energy back to each utility at the pooled price.

The functions of the ERCB and PUB are usually conducted separately. However, in 1988, the Government of Alberta, by Order in Council, directed the ERCB and PUB to hold a joint inquiry into electricity generation by independent small power producers (SPPs).

The ERCB and PUB recommended to the Lieutenant Governor in Council that:

- the Alberta Government adopt a policy to facilitate production of electric energy by SPPs;
- all types of power producers with individual generating plant capacities of 2500 kilowatts (kW) or less be classed as SPPs;
- initially a maximum of 100 MW of SPPs be connected to the AIS;
- prices paid to SPPs by utilities be based on long-term avoided costs in order to ensure that rates to consumers would not increase as a result of the SPPs; and
- SPPs should be exempted from certain provisions of the PUB Act and HEE Act.

The two agencies also recommended that a certain methodology be adopted to calculate long-term avoided costs and that certain rates be paid to SPPs that would avoid consumer price increases.

In October 1988, the Government of Alberta established the Small Power Program. The Program is currently administered by the Department of Energy and is expected to run until 125 MW of eligible SPPs are connected to the system or until 31 December 1994, whichever occurs first. An eligible power production facility would produce electric energy from solar, wind, municipal waste, hydro, geothermal, biomass, or peat resources.

Under the Program, SPP facilities, as defined in the Small Power Research and Development (SPRD) Act, together with a number of pilot projects (capacities larger than 2500 kW) receive a rate established by legislation. This rate is higher than that recommended in the inquiry report. The higher rates were adopted to encourage development of small independently-owned generating facilities using renewable resources. Owners of units under the Program may also recover some of their income taxes paid, pursuant to the Utility Companies Income Tax Rebate Act.

The HEE Act was amended to accommodate generating units under the Program. The ERCB now considers applications for approval of units under the Program without regard to whether they are needed or whether they are an economic source of power. Since the rate is fixed by legislation, units under the Program are also exempt from the PUB Act. However, SPP contracts are required to be acceptable to the PUB.

3 DEFINITION OF ISSUES

The Board has considered the application, submissions, and testimony provided at the hearing and considers the relevant issues to be:

- need for and timing of the proposed project,
- associated costs and benefits,
- interests of the community of Stettler,
- environmental concerns,
- connection to Alberta Power's electric system, and
- implication of the application with respect to future needs of the AIS.

4 NEED AND TIMING

4.1 Views of the Applicant

ECI acknowledged that the Electric Utility Planning Council (EUPC) forecast is the latest available to the Board to determine need for new capacity. However, it stated that, because forecasting is an inexact science, the EUPC's forecast may not be accurate. Nevertheless, ECI said it is prepared to accept the forecast for what it is – an inexact exercise and about 70 per cent accurate.

ECI stated that the forecast basically extrapolates current economic conditions to predict future requirements for electric energy in the province. It acknowledged that the current EUPC forecast shows a drop in demand growth relative to previous forecasts and expressed the view that the forecast reflected the current world recession. It explained that, because the lower forecast indicates that the plant's output would not be needed until late in this decade, Alberta Power broke off negotiations with ECI in September 1990.

ECI suggested that, if the economy were to improve, a new forecast may show a much higher growth rate and need for new capacity may occur earlier than what the utilities are predicting today. ECI said that, with general elections expected within a few years, a sudden boom in the economy is very likely.

ECI said it is also possible that future reviews of the EUPC forecast may show that something has been overlooked in the current forecast. Therefore, a new EUPC forecast may result in need for generating capacity sooner than 1997.

ECI also pointed out that forecasts of electric requirements in Manitoba show higher growth rates than the EUPC forecast does for Alberta. It expressed the view that Alberta should have higher growth rates than Manitoba and contended that the EUPC forecast is pessimistic.

ECI stated that its proposed plant can be built in approximately 18 months, while a typical utility-owned coal-fired plant requires approximately 10 years to construct. Therefore, its proposed plant is a better choice, since it can respond quickly to an unforseen need for capacity.

ECI submitted that when utilities build large plants they have to spend large amounts of money well in advance of need. Later, if need is delayed and the commissioning date is reviewed, utilities argue that they have to maintain the original commissioning date to protect the money already spent. As a result, ratepayers usually end up paying for capacity which is not needed at the time of commissioning.

ECI suggested that between now and 1996 a need could arise for a small increment of capacity on the AIS rather than a large utility plant. ECI referred to this situation as a "slot" for new capacity and submitted that its proposed 25-MW plant could be allocated to any of these slots. However, ECI acknowledged that, if a slot were to occur before 1997, there may be other ways of meeting that need as opposed to building new capacity.

ECI disagreed with the calculations of need for new capacity submitted by the utilities. It doubted the availability of capacity assistance from British Columbia (B.C.) Hydro (400 MW) and Saskatchewan Power Corporation (SPC) (100 MW beginning in 1995). It claimed that contracts between TransAlta and B.C. Hydro and between Alberta Power and SPC for capacity assistance are not public documents. Therefore, it is not possible for ECI, or any other interested party, to review them and find out how secure the capacity assistance really is.

ECI stated that it is prepared to either advance or defer the commissioning date of its proposed plant, but not later than 1997. However, it is not prepared to re-file its application closer to a date by which the plant might be needed. Instead, it preferred to adjust the documentation to reflect changes in economic and environmental conditions.

4.2 Views of the Interveners

EUPC

The EUPC did not take a position respecting need for or timing of the applied-for facilities. It appeared at the hearing to present its 1992 Alberta Electric Forecast Working Range for Resource Planning and to answer questions relating to it. It explained that the forecast is structured to consider a range of possible outcomes, bound by a high and a low electric forecast, rather than to produce the most probable forecast. The actual electric load in Alberta is expected to fall between the high and the low bounds with a probability of 70 per cent. The EUPC uses a working range or scenario concept in order to deal with the inherent uncertainty in forecasting future load growth.

The EUPC presented evidence outlining the major assumptions that are built into its forecast. The first set of assumptions relate to Canadian macroeconomic factors. Of these, inflation and interest rates have the greatest effect on the Alberta economy in terms of electric load growth.

The second set of assumptions relate to world oil and North American gas price forecasts. From these assumptions a set of expectations was developed with respect to production of crude oil and natural gas. That information was fed into an econometric model of the Alberta economy and a forecast of the province's economic performance was developed. The provincial Gross Domestic Product for the high growth scenario is forecast to average 3.2 per cent in real growth over the forecast period and 0.6 per cent for the low growth scenario.

To derive the high bound, oil prices were assumed to rise to $176 per cubic metre ($28.00 per barrel) by 1998 and to remain flat thereafter, representing 2.6 per cent real growth between 1991 and 2000. For the low bound forecast, an oil price of $100.00 per cubic metre ($16.00 per barrel) by 1992 was assumed, with prices remaining flat throughout the remainder of the forecast period.

The Alberta field price for natural gas used to derive the high bound forecast was assumed to be $2.50 per gigajoule (GJ) by 2000, representing 7 per cent real growth per year between 1991 and 2000. For the low bound forecast, gas prices would decline from the current level in 1992 and then recover to $1.42 per GJ by 2000.

The third set of assumptions relate to identifying major projects, $50 million or greater in value, which might be developed. The EUPC looked at various industrial sectors and made assumptions regarding the likely development of plants in each sector and added those assumptions to the model. For the high bound forecast, major project investment totalled $13 billion (1992 dollars) by the year 2000. Of this amount, 47 per cent occurred in the oil and gas sector, 18 per cent in chemicals, and 35 per cent in forestry. For the low bound forecast, major project investment totaled $7.5 billion by 2000.

The EUPC explained that, once the forecast of overall electric consumption in the province is developed, a number of adjustments are carried out. Forecasts of potential load served by self-generation as well as that of isolated load, both of which are not served by the AIS, are removed from the forecast of utility-supplied requirements. The next adjustment to the forecast is to subtract load that will not materialize because of utility sponsored energy efficiency programs. The final adjustment is for interruptible service, for which the utilities do not plan any capacity and which is, therefore, removed from the final load that must be supplied.

The EUPC submitted that, considering all the assumptions and adjustments mentioned above, the low bound forecast scenario results in a 1.1 per cent annual growth rate in electric energy use over the forecast period while the high bound forecast results in a 3.3 per cent average growth rate. In terms of peak demand the average growth rate in the high bound forecast is 3.5 per cent while for the low bound forecast it is 1.4 per cent.

Alberta Cogeneration Council (ACC)

The ACC submitted that it is not in a position to address how well this particular application meets the purposes of the HEE Act. However, the ERCB decision should clearly indicate that the existence of surplus capacity on the AIS does not preclude additions of non-utility generators. The ACC regards the ECI proposal as a "waste utilization project" which should be approved regardless of existing surplus capacity.

Alberta Federation of Rural Electrification Associations (Federation of REAs)

The Federation of REAs submitted that, conceptually, it favours cogeneration projects and small increments of generating capacity additions to the AIS. However, currently the AIS has an excess of generating capacity and Genesee Unit No. 1 has been approved to be commissioned in 1994. Therefore, the AIS does not need the generating capacity of the ECI project. The Federation of REAs pointed out that the short time needed to construct the ECI project suggests that the application can be made closer to a time when capacity is needed.

The Federation of REAs also submitted that approving the project now would preclude alternative projects which may be of more benefit than the ECI project. Therefore, the ERCB should adjourn the application and assess it against other projects, including Demand Side Management (DSM) projects, at a later time when new capacity is required.

D. Wozney

Mr. Wozney submitted that need for new generating capacity should be satisfied primarily by coal-fired power plants. Small-size gas-fired power plants should only be used as temporary sources of generating capacity during periods when coal-fired plants are under construction and reserve capacity drops to below 20 per cent.

Industrial Power Consumers Association of Alberta (IPCAA)

IPCAA submitted that the application should be denied because ECI has failed to demonstrate that additional generating capacity is required by the AIS.

TransAlta

TransAlta submitted that the proposed ECI facility is not needed and the application should be denied without prejudice. To do otherwise would ignore the competitive procurement process (CPP) being developed by TransAlta and the effect it might have on determining what new capacity is added to the AIS. An approval of ECI's proposal would encourage other potential suppliers to apply resulting in competition based on joining a queue rather than competition based on competitive bidding. Denying the application without prejudice would allow ECI to re-apply when an approved CPP is in place.

TransAlta noted that currently there is a generation reserve sharing agreement between it and B.C. Hydro for 400 MW of reserve capacity and between Alberta Power and SPC for 100 MW which becomes effective in 1995. The interconnection facilities between Alberta and Saskatchewan have existed since 1989 while the present 500-kilovolt (kV) interconnection with B.C. has been in service since 1986. In addition there are two 138-kV interconnections with B.C. TransAlta testified that such agreements allow for mutual emergency support for each others systems and make it possible for the utilities to build less generating capacity while continuing to provide the same level of reliable service. TransAlta explained that, because of the reciprocal nature of these agreements, where each party relies on the other for the same amount of mutual support, there is no net payment for the capacity provided. For any energy provided during such support a nominal energy charge is incurred.

With respect to current need for new generating capacity, TransAlta noted that both it and Alberta Power made calculations based on the 1992 EUPC forecast and using current planning parameters. TransAlta determined that in the case of the high forecast there would be a 5-MW deficiency in required capacity in 1997 while Alberta Power calculated there would be a deficiency of 3 MW in 1997, virtually an identical result. TransAlta submitted that, given the small amount of additional capacity required in 1997, it is more reasonable to conclude that a new plant might be needed by 1998, at the earliest, rather than 1997.

City of Calgary

The City of Calgary argued that capacity should be added only when it is required by the AIS. Noting that new capacity will not be needed before 1997, and possibly not until 2003, it contended that adding capacity before it is needed will increase the current surplus of generation and the cost to Alberta consumers. The City of Calgary also argued that, because ECI's proposed plant can be constructed in two years, there is no need to approve it at this time.

Edmonton Power

Edmonton Power argued that to approve ECI's application there must be a demonstrated need for capacity, under current demand forecasts, which is consistent with the project's construction time.

Approving the project now would be both premature and unnecessary. It also contended that approval now would preclude the possibility of other competitive projects being considered when capacity is needed. Edmonton Power stated that applications made closer to the date when new capacity is needed would embody technological advances which may occur in the intervening period.

Alberta Power

Alberta Power stated that its discussions with ECI in 1989 were very preliminary in nature and similar to those it normally has with other potential developers. In September 1990 it became clear that expected demand growth was not materializing and the AIS would not require additional capacity for several years. Alberta Power explained that, because of the lack of need, it advised ECI at that time that it would not be able to support or participate in the project.

Alberta Power submitted calculations of need for new capacity by the AIS based on the latest EUPC forecast. It indicated that, if the high growth scenario forecast were to materialize, new capacity would be needed by 1997 or 1998. If the low growth forecast were to materialize need would occur around the year 2003. Alberta Power explained that need for new capacity is driven not only by load growth but also by decommissioning of older generating units currently existing on the AIS. The decommissioning dates of these units are not fixed but are subject to the mechanical condition of the units. Therefore, it is possible, through reconditioning and/or refurbishment, to prolong their life. If this were to happen, need for new capacity would move even further into the future.

With respect to the applicant's doubts about capacity assistance from neighboring power systems, Alberta Power advised that it has a contract with SPC which very clearly specifies the amount of mutual capacity assistance. Furthermore, this contract was filed by Alberta Power as part of its original application to the ERCB for approval of the interconnection with SPC and is, therefore, a matter of public record.

Alberta Power contended that ECI's application should be denied on the basis that the project is not needed or, given that construction time for the project is less than two years, it could be considered at a later time, closer to when new capacity is needed.

4.3 Views of the Board

The only forecast of future electric requirements presented was the 1992 EUPC forecast. Discussion respecting need centred around projections set out in that forecast. The Board believes the economic parameters chosen by the EUPC are appropriate for the purposes of creating high and low growth forecasts which define a suitable working range for planning purposes.

The Board has reviewed the list of major project investments expected throughout the forecast period and, except in the case of heavy oil production in the high growth scenario, generally believes that the EUPC's list is reasonable as to number, type, and timing of projects. The Board expects a lower rate of development in the area of heavy oil production than that assumed by the EUPC. However, the impact is minimal because most new production capacity is forecast to occur after the year 2000, beyond the period of greatest interest in determining need for the proposed power plant.

The Board has considered the various reasons suggested by ECI as to why the EUPC's forecast should be placed in doubt. No information was provided to support the suggestion that the economy will improve rapidly and a higher growth rate will occur, or that a sudden boom will follow general elections, or that Manitoba's growth rate has implications for Alberta. In the absence of such information, the Board cannot accept ECI's suggestions.

The Board concludes that the 1992 EUPC forecast is suitable for use as one of the starting points in determining need for new generating facilities for the AIS. The EUPC forecast is presented as a range of scenarios of possible load growth. It may, therefore, be characterized as defining a period of time during which need for new capacity may arise.

The estimation of need for new capacity relies on accepted procedures and criteria which are well defined and have been the subject of previous reviews by the ERCB. Alberta Power and TransAlta estimated need in accordance with this accepted practice. Therefore, the Board is prepared to accept that new facilities will not likely be needed before 1997, perhaps not until 2003 if the low-growth forecast were to materialize, or even later if some older units are not decommissioned as currently planned.

In considering whether need may occur either early or late in the range defined above, the Board notes that the EUPC assigns equal probability to the load falling anywhere between the high and low scenarios. The Board believes that the current and near-term outlooks for economic growth, and consequential demand for electricity, imply that need for new generating capacity is more likely to occur later in the forecast period. Put another way, in order for need for new capacity to materialize by 1997, Alberta would have to be experiencing a high rate of growth of economic activity today and that rate would have to be sustained for the next 5 years. The Board observes that the Alberta economy is not currently growing at a very high rate and the near-term outlook offers little reason to expect a rapid increase. Therefore, the Board concurs with those interveners who contended that need for new capacity is more likely to occur in the latter part of the forecast period.

The Board acknowledges that, in certain circumstances, smaller generating units may have an advantage over larger ones, particularly because they can be built relatively quickly and hence closer to the time when new capacity is actually needed. This means increases in demand can be matched with appropriate increases in supply, avoiding large blocks of surplus capacity. However, the advantage of this flexibility must be balanced against the possibility that, in the longer term, a larger unit may be able to generate power at a lower overall cost. In the case at hand, the existing surplus capacity is likely to last until the end of the decade. Therefore, it may be more prudent to defer considering projects having a short lead time, such as ECI's, until closer to the time when they are needed. This would ensure that all options having a short lead time can be considered.

The applicant presented no evidence to substantiate its claim that a temporary need for a small increment of capacity may suddenly appear between now and 1997. However, should such a need arise, the Board notes that the utility companies could implement temporary measures, such as short-term firm power purchases from neighbouring power systems, to assure the supply of electric power.

The Board recognizes that cogeneration plants can be a very efficient and cost effective source of electric energy. However, the operation or requirements of the commercial or industrial process to which they are tied may not match the needs of the AIS. Therefore, cogeneration may not necessarily be the most appropriate choice for the AIS in all cases. If the cogenerator were prepared to accept the entire risk of such a mismatch, or if a suitable contract were negotiated which shared the risks and benefits appropriately, there would be little basis for rejecting it. However, if an assured price for power supplied to the AIS is being sought, as in this case, then this becomes a significant issue.

The applicant testified that the greenhouse may be developed in stages of 10 to 20 acres at a time and that it may take several years for the greenhouse to be developed to a size that would fully utilize the heat produced by the power plant. This suggests that the proposed power plant may not be essential as a source of heat for the initial stages of greenhouse development.

With respect to the ACC submission that "waste to watts" projects should be approved irrespective of the existence of surplus capacity, the Board cannot assign weight to this argument in this case. The ECI project would burn natural gas to generate power. Therefore, the Board does not consider it a "waste to watts" project.

Notwithstanding the Board's view that the likelihood of needing new capacity in the near term is low there may be other features of the proposed project that would warrant its approval. These are examined in the following sections.

5 COSTS AND BENEFITS OF THE PROJECT

5.1 Views of the Applicant

ECI submitted that its proposed power plant can be built in less than 20 months at a cost of $27 million. It explained that 6 months are necessary to complete pre-engineering design work. The supplier can deliver the turbine in less than 12 months and two months are required for installation.

ECI stated that the cost of its power plant would be higher than that of a standard gas-fired turbine of similar size because its proposal calls for a combined-cycle plant with heat recovery steam generation, water conditioning facilities, steam-injection facilities, etc., and the plant would be located on a new site. ECI also mentioned that its cost estimates were comparable to Alberta Power's estimates for recently proposed 40-MW and 20-MW gas-fired turbines at Rainbow Lake. However, its proposal is better because consumers would not have to bear potential cost overruns, unlike utility-built plants where cost overruns are passed onto consumers.

ECI submitted that the greenhouse-cogeneration plant is a complete package that would cost approximately $48 million. The size of the power plant is based on the thermal requirements of the greenhouse, especially during winter. Operating the power plant at full capacity during summer would create a surplus of steam, part of which would be injected into the turbine to increase efficiency and control nitrous oxides (NO_x) emissions. ECI submitted that the cogenerating plant would achieve an overall thermal efficiency of 65 to 80 percent. ECI also indicated that the sale of electric energy from the power plant would contribute to the viability of the project. During cross-examination, ECI accepted that a smaller cogenerator, for instance 5 MW, would also be viable. However, it indicated that a smaller greenhouse would have to be developed in that case.

ECI stated that cash flows showing the economics of the greenhouse were prepared using a generic method that assumed that 10 million pounds of tomatoes per year would be produced for 20 years. However, it explained that this is just an evaluation method and that the actual greenhouse would probably be constructed in stages of 10 or 20 acres at a time and production would be determined by the greenhouse operator based on market requirements. ECI mentioned that it had held talks with a Dutch company which expressed interest in becoming an equity participant and operator of the greenhouse.

ECI stated that financing for the project would likely come from capital markets which currently support the cogeneration sector in the United States of America (USA). Since the implementation of the Public Utilities Regulatory Policy Act (PURPA), this sector has grown to more than 10 000 MW.

ECI testified that it would seek non-recourse financing, which means that an investor is at risk only to the extent of its equity investment. However, to obtain non-recourse financing it is necessary that the following contracts be in place: (i) a power sales agreement; (ii) a contract with the equipment vendor, specifying price, warranties, and equipment performance; and (iii) a fuel supply contract.

ECI also explained that, with non-recourse financing, it and the Town would be at risk for only their respective equity contributions while the lender would be at risk for all the remaining capital needed to implement the project.

ECI mentioned that greenhouses with cogenerating plants are viable and that it is aware of several operations of this nature currently existing in the USA. It explained that, because the thermal energy from the cogenerating plant to the greenhouse is constant and its cost well defined, the greenhouse operation is immune to volatile energy prices. During cross-examination, ECI stated that a contract with a utility for the sale of electric energy, which would ensure a secure revenue stream, is very important to the entire project's viability. The greenhouse would likely not be viable without the cogenerating plant.

ECI testified that total power sales to Alberta Power, over a period of 20 years, would amount to approximately $200 million, or $70 million in present worth terms. A quantitative analysis filed after the hearing, as part of an undertaking, shows that, under ECI's proposed pricing scheme, the present value of power sales to Alberta Power over a period of 35 years would amount to $107 million.

ECI submitted that, after 20 years of operation, it would be willing to give the plant away for a nominal amount of $1. Having an expected life of 35 years, the plant would still have 15 years of useful operation and would be fully paid for. However, whoever gets the plant after 20 years would have to accept full responsibility for any decommissioning or dismantling costs which ECI estimated would be in the order of $750 000. ECI also submitted that, if it were to retain ownership, it would operate the plant for 35 years. In that case it would be prepared to set aside a decommissioning fund to be used after year 35 to properly dismantle the plant and reclaim the site.

ECI stated that its proposal is a very competitive one. There is a firm contract in place with the turbine vendor that is flexible with respect to the commissioning date. Therefore, ECI considered that its application deserved to be approved even though the AIS has surplus capacity. Furthermore, an early approval would allow ECI to assure gas reserves at very convenient gas prices and take advantage of current low interest rates. ECI stated that it believes that these economic advantages would not last for very long. Therefore, if the project were deferred, these advantages would be lost. ECI submitted that, to obtain financing, 1997 would need to be the latest commissioning date for the plant. It contended that 1996 is a more reasonable commissioning date to assure financing.

ECI asked the ERCB to evaluate the project as a whole, including not only the socio-economic benefits arising from the greenhouse but also the environmental benefits resulting from lower emissions.

5.2 Views of the Interveners

Federation of REAs

The Federation of REAs submitted that, to support this application, it requires assurances that the project would not impose costs to its members in the short term or, if there is a short-term cost, it would be outweighed by long-term savings. It stated that the application necessitates detailed inquiry into the economics of the project.

D. Wozney

Mr. Wozney opposed approval of power plants, such as the plant proposed by ECI, that would burn natural gas to generate electric energy. He submitted that natural gas would be better used if it were exported, through existing pipelines, to supply markets outside the province.

IPCAA

IPCAA submitted that the ECI proposal is not competitive because ECI is not responding to a need for new capacity by the AIS. Instead, it is applying to satisfy its own need or desire to build a project. Moreover, it is not competing against any other proponent to provide the next 25 MW of capacity.

Edmonton Power

Edmonton Power argued that the applicant's projected cash flows for the greenhouse are based on the sale of theoretical volumes of tomatoes without examining market realities. Therefore, it is impossible for the Board to determine the financial viability of the greenhouse.

Edmonton Power also argued that it would be imprudent to approve this project now because there is no evidence that the natural gas fuel source, on which the project is dependent, is secure for the entire life of the plant.

City of Calgary

The City of Calgary stated that the applicant has neither demonstrated that the project is financially viable nor that it is the least-cost generation option.

Alberta Power

Alberta Power expressed doubt that the greenhouse would be a viable operation. It pointed out that the applicant does not know what the greenhouse would produce. Therefore, revenues from the sale of produce are unknown. Also unknown is the status of the commitment by a Dutch company, mentioned by the applicant, that would assure continued operation of the greenhouse.

5.3 Views of the Board

The Board notes that the power plant rating is 25 MW whereas the peak electric demand of the greenhouse is 3 MW. Furthermore, the greenhouse would utilize only 42 per cent of the annual thermal output of the power plant. Although part of the waste heat would be used to generate steam for injection into the turbine to boost power production and reduce NO_x, there would still be excess waste heat for 7 months of each year. While ECI suggested other users for the steam might be found, none were identified. This suggests to the Board that, in the absence of any additional steam users, the overall thermal efficiency of the project would be somewhat lower than suggested by ECI.

The Board observes that the applicant could have sized the power plant to more closely match the electric requirements of the greenhouse. Additional steam requirements during cold weather conditions could be supplied by supplemental firing of the steam generator. Financial information supplied by the applicant suggests that a greenhouse project of this nature might still be viable. Moreover, ERCB approval of a power plant would not be required if the power generated were used solely for the greenhouse.

The Board notes the applicant's view that a greenhouse cannot be financially viable without an accompanying power plant because of high energy costs to heat and power the greenhouse. However, the applicant's projections show that the difference between heating the greenhouse using purchased gas and heating it with steam produced by the power plant is only about $100 000 per year. Furthermore, with respect to purchasing electric power from the AIS, industrial electricity rates in Alberta are among the lowest in the world. Given the projected revenues provided by the applicant, the Board concludes that the purchase of energy from outside sources would not unduly affect the viability of the greenhouse.

The Board acknowledges the concerns expressed by some of the interveners respecting the theoretical revenue projections from the sale of assumed volumes of tomatoes. Nevertheless, if those projections are correct, it appears the greenhouse would be a viable operation on its own. Also, the fact that the greenhouse may be developed in stages, combined with the participation of an experienced partner in its development and operation, would appear to enhance its viability. The Board concludes that ECI's proposal is intended more as a power generating and sales venture than as a greenhouse project with facilities to supply electric energy and heat to it. In any case, on the evidence presented by the applicant, the Board is not persuaded that approval of the power plant is essential to the viable operation of the greenhouse.

6 COMMUNITY ISSUES

6.1 Views of the Applicant

The applicant submitted that the proposed project would benefit the agricultural sector and provide supplemental income for the farm community. It stated that it also expected it would reverse the current population decrease. It suggested that benefits to the community would arise as a result of economic diversification, economic growth, employment opportunity, increased industrial tax base, and water sales to the greenhouse.

The applicant also submitted that, under the Municipal Government Act, the Town is able to enter into joint ventures with private developers for up to 25 per cent equity participation without being liable for losses that might be incurred by the private developer. However, it acknowledged that, if the project were to fail, the Town's equity participation would be at risk. The applicant indicated that the Town's commitment to the project in land, access roads, site grading, and cash outlay is $387 500.

The applicant stated that continuation of the franchise between Alberta Power and the Town is not contingent on Alberta Power supporting the project.

ECI submitted that despite some minor opposition to the project, which it considered to be generated by the utilities, it felt a moral obligation to develop this project in Stettler.

6.2 Views of the Interveners

County of Stettler No. 6 (County)

The County submitted that the proposed project would create 90 to 100 jobs in the area and allow the farming community to have access to non-farm related income. The project would also make Stettler economically stronger and more attractive to outside industries as well as strengthening the existing industry and local business base. All these prospects would bring benefits to the community.

The County expressed concerns regarding the use of groundwater in the operation of the proposed project. However, it stated that it had been assured that use of groundwater would be considered only after proper permits are obtained.

Mr. Dodds

Mr. Dodds supported the project because it would provide good industrial development for Stettler. He stated that he believed in a free market for electric power and mentioned that Stettler should have the option of producing some of the power it consumes.

Downtown Merchants' Association of Stettler (Merchants' Association)

The Merchants' Association submitted that the impact created by a cogenerator in Stettler would boost the local economy and generate business directly for the town's merchants as well as spin-off business in the long term.

Town of Stettler (Town)

The Town submitted that the project would attract young people back to Stettler and help reverse the migration to larger cities and corresponding population decrease. Also, it submitted that Stettler needed this project to counteract the loss of employment which has occurred in the past. The greenhouse development would require approximately 80 employees and would diversify the local economy into the food processing field. The cogenerating plant should attract other industries that require low cost heat.

The Town contended that development and construction of the cogenerating plant and greenhouse would cause a flow of capital into the Stettler area in the order of $6 million. In addition, the project would pay over $400 000 in taxes and would increase water sales by $300 000 per year. As an equity participant, the Town could expect an annual return of $230 000.

Stettler Economic Development Board (Development Board)

The Development Board's mandate is to promote economic initiatives that assist in creating employment, sustaining existing industry, and encouraging new companies to locate in Stettler. Hence, it supported the proposed project.

The Development Board stated that a survey conducted in Stettler showed that 65 per cent of the people who responded are in favour of the greenhouse-cogeneration project. Of those same respondents, 48 per cent were in favour of the Town becoming an equity participant in the project while 40 per cent were opposed and 12 per cent per were undecided.

The Development Board submitted that the Town's involvement would consist of providing the developer with serviced land and a maximum payment of $162 500. It estimated that the yearly gain to the Stettler area would be approximately $2 million. Also, there is a potential for an average reduction of 9.43 per cent in residential taxes.

R. Somerville

Mr. Somerville supported ECI's proposal to utilize waste heat produced after the generation of electric energy and asked the ERCB to give favourable consideration to this aspect of the application.

D. Wozney

Mr. Wozney submitted that there are a considerable number of sites in the province, with similar features to Stettler, where the proposed project could be built. Some of these have the further advantage of being closer to existing sources of heat which are not being utilized.

Stettler & District Chamber of Commerce (Chamber of Commerce)

The Chamber of Commerce did not support the Town having an equity interest in the cogeneration project. It expressed a belief that, in the event of failure of the project, the Town would not only be risking its equity participation but would also be responsible and subject to liability for loss of the debt portion of the capital. It submitted that the cost to develop and service the property should not be borne by the community until there are assurances that the project is viable and financing is in place. The Chamber of Commerce further submitted that no government body should have equity or operating interest in a private enterprise. It asked the ERCB to investigate the viability of the project and look into environmental effects on air quality, noise, soils, water, and wastes.

The Chamber of Commerce also expressed concerns about the effect the proposed project may have on Alberta Power's investments in Stettler. If the project were approved, Alberta Power may not continue to keep employees in Stettler, build structures, and contribute to the town's tax base.

Edmonton Power

Edmonton Power stated that it understands the concerns of the community of Stettler. Many communities in Alberta are similarly affected by flat economic growth, aging work force, decreasing tax base, and need for jobs. However, the AIS must be developed for the benefit of every Albertan. Therefore, the Board's decision on this application should benefit every Albertan and not just a single company or community.

Alberta Power

Alberta Power indicated that it has served Stettler for the past 65 years and currently has 17 employees permanently stationed there. The proposed project is unrelated to its presence in the town and its people would not be moved if the ECI project were approved.

Alberta Power's franchise with the Town expired last year and it is important to both the Town and Alberta Power to have a new franchise signed as soon as possible. However, Alberta Power indicated that if a new franchise is not signed it will continue to operate its power system and serve the town as it has done in the past. Alberta Power advised that the Town inquired into the possibility of buying the local electric distribution system. It indicated to the Town that its power system is not for sale. However, if it were forced to sell its local power system to the Town there would be no need for Alberta Power to remain in Stettler.

6.3 Views of the Board

The Board agrees with the applicant and those interveners who contended that the community would benefit from a project of this magnitude. These benefits might include new employment opportunities, diversification of the local economy, business spin-offs, increased revenues to the community, and a decrease in migration of local residents to larger urban centres. However, the benefits to the local community must be considered from the perspective of the province as a whole. For example, the Board believes that, if the subject project were located in another community in the province, the associated benefits would be realized by that other community and, from a provincial perspective, there would be no particular advantage to one location over the other. Therefore, the Board must be careful not to assign too much weight to potential benefits to any local community.

The Board observes that, in the case of ECI's proposal, these benefits are largely attributable to the greenhouse and not the power plant. Presumably if a greenhouse alone were to be built in Stettler, it would provide the town with most of the benefits attributed to this project.

Little evidence was presented regarding non-recourse financing. However, based on its knowledge of this manner of financing, the Board believes that if the project were approved and it proceeded as proposed, only the Town's equity, or what it has contributed to the project, would be at risk.

7 ENVIRONMENTAL CONCERNS

7.1 Views of the Applicant

In its application, ECI indicated that its proposed plant would emit no sulphur dioxide (SO_2) and only 25 to 42 parts per million, by volume, of NO_x. ECI also stated that NO_x emissions are estimated to be 152 tonnes (167 tons) per year.

During the hearing ECI submitted that its proposal to generate electric energy using a natural gas-fired turbine would result in less emissions than generation by a coal-fired plant. However, during cross-examination, ECI acknowledged that emissions from the proposed plant could affect air quality in Stettler under certain weather conditions, although not dramatically. For that reason, it chose to locate the plant in the north-east corner of town, where prevailing winds would disperse emissions away from the town. ECI stated that reducing emissions would not only have local but also national and international benefits.

ECI estimated that noise from the power plant would be 50 decibels at 100 metres from the turbine generator set. It stated that noise levels at the nearest residence would be within permissible levels as outlined in the ERCB's noise control directive. However, if after the plant is built, noise levels turn out to be higher than permissible, ECI would provide noise attenuation measures.

ECI mentioned that liquid discharges from the power plant would be chemically neutralized and disposed of by acceptable methods, yet to be determined.

7.2 Views of the Interveners

Edmonton Power

Edmonton Power stated that the proposed gas turbine would burn fossil fuel and release pollutants. Additionally, the greenhouse and cogenerating plant would require the consumption of 456 000 gallons of water a day. It pointed out that an environmental impact assessment had not been conducted for the project and a waiver of that requirement had not been obtained by the applicant.

D. Wozney

Mr. Wozney submitted that the applicant neither quantified nor documented the social cost of emissions from coal-fired generating plants in Alberta. Instead, it simply used information applicable to the State of California, which is not relevant to Alberta.

7.3 Views of the Board

The Board acknowledges that the proposed power plant, fired by natural gas, would have low SO_2 emissions and that NO_x emissions could be held within allowable levels. Furthermore, because the proposed gas turbine would use steam injection, the Board believes that there should not be any problem in controlling NO_x emissions even if future legislation were to become more restrictive. Nevertheless, if the project were approved and some negative environmental impacts were to surface during operation, the ERCB and other government agencies that enforce environmental standards would ensure that all environmental standards would be met. This applies to emissions of gases to the atmosphere, use of water and its disposition, noise pollution, etc.

The Board notes the applicant's submission that there is a social cost if electric energy is supplied from coal-fired generating plants rather than gas and that the cost should be reflected in the pricing of energy. The Board agrees that, if energy from the proposed plant were to displace only coal-fired generation, that amount of energy would be produced with less SO_2 and NO_x emissions. However, the decrease in emissions would be relatively small when viewed in the context of the energy produced by all electric generating plants in Alberta. On the other hand, if energy from the proposed plant were to displace gas-fired generation there would be no difference in SO_2 and NO_x emissions. Moreover, if hydroelectric generation or energy imported through tie-lines were to be displaced, then the proposed plant would increase overall emissions in Alberta.

The Board concludes that the environmental impact of the proposed plant would be small, be it positive or negative, and not a significant factor in deciding to approve or deny the application.

8 CONNECTION TO ALBERTA POWER'S ELECTRIC SYSTEM

8.1 Views of the Applicant

Physical Connection

ECI proposed to connect its power plant to Alberta Power's electric system by stepping up the voltage to 72-kV and constructing a transmission line to a nearby substation. ECI estimated the cost would be $850 000, excluding the transformer. It indicated that the cost of the transformer is included in the power plant cost estimate. It also indicated that its cost estimates include a contingency amount in case the cost to connect its plant to Alberta Power's electric system turns out to be higher than estimated.

Energy Transfer Compensation

In its original application, ECI requested the ERCB to value the output of the power plant at the same prices offered by the Small Power Program. During the hearing, ECI elaborated on its request, stating that the principles and method for determining avoided costs as well as the prices set out in the inquiry report should be the basis for developers like itself to negotiate with the connecting utility. However, it doubted that those prices represent the true avoided cost. ECI also testified that the proxy method described in the inquiry report is a reasonable method for calculating avoided costs and indicated that a proxy model of the same nature is being used in some jurisdictions in the USA.

ECI stated that, subsequent to the inquiry, a report to the Minister of Transportation and Utilities was submitted by Dr. Govier, indicating that certain items identified by the Small Power Producers Association of Alberta should have been included in the calculation of avoided costs in the inquiry report. This resulted in the prices offered under the SPRD Act of 5.2 cents per kilowatt-hour (kW•h) levelized or 4.64 cents per kW•h with escalation. ECI submitted that the 4.64 cents per kW•h, with escalation, represents the closest possible figure to the true avoided costs. However, it also submitted that, because the inquiry report states that the ERCB and PUB had reservations about applying levelized costs to non-SPP projects (i.e. larger than 2.5 MW), ECI decided to price the output of its plant at 4.64 cents per kW•h with only 4 per cent escalation instead of 4.5 per cent as used in the inquiry report.

Subsequent to its original application, ECI filed supplementary information in which it proposed two other possible methods for pricing the output of its plant:

(i) a method referred to as being based on avoided cost in which the output of the plant is priced at 3.99 cents per kW•h commencing in 1990 and escalating at the consumer price index (CPI) rate thereafter with a 12 per cent escalation in 1995, or

(ii) a method based on recovering the capital and operating costs of the project. Under this method, ECI would receive a fixed $12 per kW payment for capacity plus an energy payment of 3.4 cents per kW•h in 1995 and escalating at the CPI rate thereafter.

During the hearing, ECI submitted that, in light of the current reduction in interest rates and reduced natural gas costs, it decided to amend its application, superseding method (i) by a new method. Under the new method the value of the output of the power plant is priced at 3.95 cents per kW•h in 1992 and escalated at the CPI rate or 4 per cent for a period of 20 years. ECI also offered to give the plant away for $1 after year 20. ECI stated that the proposed 3.95 cents per kW•h in 1992 represents "reduced avoided costs" because, if factors such as cost of emissions were included, 3.95 cents would be lower than the true avoided cost. ECI explained that the 3.95 cent figure was obtained from an economic analysis of the power plant, excluding any costs related to the greenhouse. It is the minimum price necessary to make the project viable and to obtain financing. Avoided fuel costs, as quoted by Alberta Power, would not be sufficient to finance this project in its early years. ECI also explained that an escalating value, rather than a levelized value, is necessary to ensure that revenues would be higher than operating costs because the latter would increase with time.

ECI contended that its amended method would leave ratepayers "revenue neutral", meaning ratepayers would not face higher rates as a result of Alberta Power buying electric energy from its project. ECI submitted that, for ratepayers to be revenue neutral, all factors have to be considered. In the case of the proposed project, reduction in emissions, the fact that waste heat would be used, and the positive impact on the community were some of the factors that should be considered. ECI stated that its method for determining avoided costs prices the output of its power plant close to the value the utilities receive when they recover their costs through rates. It argued that when utilities quote avoided costs they only refer to avoided fuel costs. However, the definition of avoided cost should be broader. In this regard, the cost of emitting SO_2 and NO_x as well as the cost of emission control equipment should be included in any calculation of avoided costs. As an example, ECI presented in its application figures currently used in California that represent the social cost of emissions.

During cross-examination ECI agreed that, if the project were commissioned before capacity is needed, the pricing method should not include payment for capacity. It stated that it would prefer a method in which the long-term avoided costs are levelized. That way, part of the capacity payment would be brought forward to the early years of the project.

With respect to method (ii), ECI submitted that it considers this an acceptable method for determining the value of the output of the power plant because it is similar to the way in which utilities recover the costs of their projects. During cross-examination, ECI agreed that this method is not revenue neutral to ratepayers.

In summary, ECI requested the ERCB to approve its amended method, namely 3.95 cents per kW•h in 1992 with escalation at the CPI rate or 4 per cent for a period of 20 years. However, if the ERCB decided to approve a different method, the price should be defined from the beginning to the end of the contract period. Then, revenues from the sale of power would be known. Furthermore, the price should escalate at least by the CPI rate.

8.2 Views of the Interveners

Physical Connection

Alberta Power

Albert Power estimated that connection costs would be approximately $1 million. This figure includes 7 kilometres (km) of 72-kV transmission line from the proposed plant to a substation south of Stettler, a new 72-kV circuit breaker, and associated protection and control equipment. The $1 million estimate excludes a step-up transformer which it assumed to be included in the project's capital cost.

Energy Transfer Compensation

Alberta Power

Alberta Power noted that the avoided costs described in the inquiry report were recommended for projects up to 2.5 MW in size while ECI's proposal is for a plant 10 times larger. The avoided costs determined by the ERCB and PUB, back in 1988, were based on the displacement of a coal-fired and gas-fired proxy unit. However, if the inquiry were held today, it would result in lower avoided costs because coal-fired generation would likely not be considered. Alberta Power pointed out that the avoided costs calculated in 1988 were clearly defined before and after capacity was needed. Before capacity was needed the avoided costs represented only the avoided fuel costs and amounted to approximately 1 cent per kW•h. After capacity was needed, the calculation included an avoided energy and an avoided capacity component, which resulted in 4.3 cents per kW•h in the year that need for capacity was defined.

Alberta Power testified that, subsequent to the inquiry, the Small Power Producers Association of Alberta claimed that the prices determined by the ERCB and PUB Boards were too low to make SPP projects viable. Therefore, the government increased the prices recommended by the two agencies, enacted the SPRD Act, and implemented the Program which allows SPP units and pilot projects to generate and sell electric energy regardless of whether it is needed or not.

Alberta Power submitted that if the proposed project were approved and ECI allowed to sell energy at a price similar to that defined in the Program, it would cost Alberta ratepayers an extra $8 million per year. It explained this was calculated considering that only fuel at other existing generating units would be avoided before capacity is needed. In addition, because the Stettler plant would be located near existing generating plants, namely Battle River and Sheerness, transmission losses would increase overall by an estimated 6.5 gigawatt-hour (GW•h) per year.

ACC

The ACC submitted that the ERCB should recommend that the PUB, in setting the price for power from a generating facility like the one proposed by ECI, be guided by the pricing principles set out in the inquiry report, that is long-term avoided costs.

IPCAA

IPCAA submitted that the price at which the applicant intends to sell electric energy from its proposed power plant far exceeds the value of energy produced by existing generating units and, if approved, would result in higher electricity rates to Alberta consumers.

IPCAA also submitted that externalities, such as the cost of emissions, are very difficult to calculate because they are not measured directly but indirectly by the cost of remedial measures which results in a tendency to overestimate the cost of externalities. To illustrate this, IPCAA pointed out that in the application the cost of emitting carbon dioxide (CO_2) is represented by reforestation expenses, which IPCAA considers to be unrelated to actual societal cost of increased levels of CO_2. Furthermore, using this approach could result in the cost of reducing CO_2 far exceeding the benefit.

IPCAA submitted that, if externalities are included, they should only be relevant when ranking different projects for comparison purposes. Externalities should be used in cases where a selection has to be made between two projects from which power would be sold for the same price. However, externalities should not be included in pricing the electric energy which is generated by a project. Similarly, local benefits and socio-economic benefits should be considered only to rank projects.

TransAlta

TransAlta stated that environmental factors should be considered when making resource planning decisions. However, it did not agree that environmental costs should be treated as suggested by the applicant.

TransAlta noted that in 1990, the Alberta Government announced a broadly based public consultation process called a Clean Air Strategy for Alberta. An advisory group received input from the public and in 1991 made a set of recommendations to the Ministers of Environment and Energy. One recommendation was for the ERCB to coordinate a broad investigation of how externalities associated with various energy projects should be taken into account in government decision making. In this respect, TransAlta expressed support for a broad and thorough review of this matter by a full set of stakeholders. It objected to a narrow review of the matter by a subset of stakeholders at this hearing.

TransAlta questioned whether the ERCB had authority to establish the basis for determining the value of the plant output, but did not pursue the matter.

Edmonton Power

Edmonton Power stated that ratepayers must remain revenue neutral as a result of costs of non-utility projects. In this case, approving ECI's proposed plant, in the absence of need, and having ECI operate the plant base-loaded, offers the prospect of increased cost to ratepayers without any apparent advantage. Furthermore, it would be wrong for the Board to compel any utility to enter into a contract with ECI at a price that includes both energy and capacity at a time when the AIS has no need for such capacity.

City of Calgary

The City of Calgary noted that the applicant has not negotiated a power sales contract with Alberta Power.

8.3 Views of the Board

Aside from some differences in ECI's and Alberta Power's estimated costs, there was nothing to suggest that connecting the proposed plant to Alberta Power's electric system would present a problem. Therefore, the Board is satisfied that, if the project were approved, this would not be an issue.

The Board has examined the energy transfer compensation proposals put forth by the applicant and has made a number of observations. The objective of the SPRD Act is to encourage development of electric generating projects using renewable resources. This is achieved, in part, through statutorily set prices which include an incentive component. The proposed project would not use renewable resources. Therefore, valuing the output of the power plant the same as output from projects under the Program is inappropriate. The Board considers that, since the energy generated by the proposed plant would be ultimately paid for by Alberta consumers, the method of valuing plant output must be consistent with the public interest.

The applicant's requested price, 3.95 cents per kW•h in 1992 and escalating thereafter, is based strictly on the minimum energy price that the applicant believes would make it possible to finance the project. This may be an appropriate approach from the developer's point of view but, in the Board's view, it ignores the current circumstances of the AIS. Currently, there is surplus generating capacity on the AIS that could last until the end of the decade. The existence of surplus capacity means that increases in electric load can be supplied by existing sources of generation at an average variable cost (mainly fuel) in the order of 1 cent per kW•h. The Board concurs with Alberta Power that valuing the output of the proposed plant at the price set out in the Program would result in consumers paying an extra $ 8 million per year. At the applicant's requested price of 3.95 cents per kW•h consumers would pay in the order of $ 6 million more per year during the period the AIS does not require additional capacity. Furthermore, any relatively small environmental advantage that might be associated with this plant does not justify the valuation method proposed by the applicant.

In general, the extra costs that would be imposed on Alberta consumers under the applicant's proposal do not appear warranted by any associated benefits that might be realized from the plant. Since the applicant did not express an interest or willingness to proceed with the project at lower levels of revenue, the Board would not attempt to define a different approach to valuing plant output if it would clearly result in a significant reduction in revenues to the applicant. Should the Board approve the project, a different approach to valuing plant output would need to be established.

9 IMPLICATIONS OF THE APPLICATION WITH RESPECT TO FUTURE NEEDS OF THE AIS

9.1 Views of the Applicant

ECI stated that it endorses TransAlta's intention to implement a CPP. It stated that a CPP would serve the utilities well but doubted that it would produce generating costs below avoided costs. ECI also submitted that in the absence of a utility-sponsored CPP the Alberta Government should quickly mandate a similar process. Selection of a proponent should not be made by a utility but by a committee of stakeholders.

ECI stated that, if it were planning a project of this nature today, it would not apply for approval because of the potential for a CPP coming forward. However, until a CPP is in place, establishing a queue of approved projects to build new generating capacity is a reasonable approach. To dispose of applications that are currently before it, the ERCB could review them as if they were competing and grant approval to the best one(s).

ECI recommended that, in any future process, the ERCB should give consideration not only to generation costs but also to social and economic development benefits, environmental matters, location, and lead time when deciding "where" and "what" to approve. However, its application should not be subject to any of the processes mentioned above. It argued that its application was filed in early 1991, after 3 years of work. Discussion of a CPP had just started in February or March of

1992 and no CPP process has been put before the ERCB yet. Therefore, it would be unfair to have to re-submit its application under a CPP, especially now that its project is public knowledge.

ECI stated that its project is very competitive and would leave ratepayers neutral. It expressed doubt that any other proposal of equal nature would be better. Nevertheless, if the ERCB were to find another cogeneration project that is better, it would be prepared to withdraw its proposal.

9.2 Views of the Interveners

ACC

The ACC submitted that the ERCB should create a regulatory environment that encourages use of waste energy to generate electric power – the "waste to watts" philosophy. Even if the AIS has surplus capacity, it would be appropriate to approve waste to watts projects through an expedited process that avoids unnecessary evidence, uncertainty, and dispute.

The ACC contended that proponents of cogenerating plants are caught in a "catch 22" situation. Because utilities have a responsibility to ensure service to their customers they must build generating facilities in advance of need. If the utilities build in advance of need, there will always be a surplus. Therefore, cogenerators will never get on the system.

The ACC stated that, as a starting point, the pricing method for energy from cogenerating plants should be consistent with the recommendations of the ERCB and PUB in the inquiry report. However, given that the inquiry was held in 1988, it would be prudent to update the pricing principles to reflect existing conditions.

The ACC did not support a CPP because it does not fit with the current EEMA process of province-wide price levelization which will still be in place for a number of years.

IPCAA

IPCAA submitted that the Board should not establish a queue of generating projects because it would discourage development of other projects which could be superior. It argued that a CPP is a more logical approach for Alberta than just simply paying non-utility generators an administratively-determined avoided cost. It testified that experience with CPP in the USA has resulted in power being produced at prices lower than utilities' avoided costs.

IPCAA submitted that the ERCB should establish criteria and a process to evaluate applications of the type proposed by ECI. The process should be designed so that the best means of meeting a demonstrated need for additional capacity is selected. The current concept of one-system planning, command, and control should be replaced by a competitive market process in which each utility would be responsible for planning and obtaining electric generation supplies to meet the needs of its customers. It envisioned increments of generating capacity smaller than the typical 400-MW units being built and each utility satisfying its own requirements without having to depend on other utilities, as is now done.

IPCAA submitted that, during the period of transition to a competitive market, the ERCB should institute a review process to determine if additional capacity is needed, then a subsequent process for solicitation of proposals for building that capacity. The ERCB should establish criteria that would address a balance of load versus capacity, identify the type of capacity required, and provide built-in flexibility necessary to meet changing conditions. It recommended that any future determination of need should be segmented both as to probability and type. It explained that probability of need is tied into the low, probable, and high scenarios of the load forecast. A low forecast would be the most probable to occur; higher growth forecast scenarios less likely. Type of need should be classified based on the expected capacity factor of the required generating capacity. New capacity should be selected according to a least-cost generation expansion criterion.

IPCAA suggested that, once the need and type of new capacity are identified, utilities can issue requests for proposals. The ERCB should have a process in place to evaluate the different proposals. In this respect, utilities' avoided costs should be the benchmark or ceiling price against which a successful bidder is selected.

TransAlta

TransAlta stated that it is committed to establishing a competitive marketplace for electric energy generation and has announced plans to develop a competitive bidding process to supply 100 to 200 MW by 1996 or 1997. However, in light of the latest EUPC forecast, it may have to revise the date by which new generation is needed. Initiatives are now under way to evolve a new regulatory framework, a competitive electricity marketplace, and a means to determine an appropriate way to consider environmental impacts.

TransAlta stated that it has requested the PUB to schedule a hearing for the Fall of 1992 to deal with the evolving market for electric services in Alberta, including transmission access, unbundling of services, and standby rates. Also, the Government of Alberta has invited comments on a new regulatory framework for the electric power industry in Alberta, including competitive procurement.

Responding to questions by ECI, TransAlta stated that it believed avoided cost, as it is traditionally calculated, i.e. utility's avoided cost using traditional utility options, is not an appropriate way to look at what avoided cost might be in the future. Rather, a utility should call upon the marketplace, through a CPP, to determine what the market clearing avoided cost might be, which is what it is proposing.

Alberta Power

Alberta Power stated that slow growth in the projected demand for electric power in the province lends support to the notion that it is more prudent to add small increments of capacity rather than the typical 400-MW units of the 70s and 80s. It also stated that many of the future small capacity increments will be proposed by non-utility developers. Therefore, a process is needed to deal with those new proposals. It recommended that, in the future, only proposals that satisfy a well established need for capacity should be considered. A CPP is one of the possible processes that the Board may consider. The objective of such a process is to ensure the lowest possible rates for electric service.

Alberta Power submitted that the Board should not grant allocation or establish a queue of proposals waiting to build the next increment of capacity based on when the applications are made. Rather, there are several options available to satisfy future generating capacity needed by the AIS. They include: new utility generating units, refurbishment of existing units, reliance on neighbouring power systems, new non-utility generating units, DSM, and acceptance of a lower standard of reliability. Having all these options, together with a selection process, would improve the ability of utilities to respond to future needs in the most cost-effective manner.

City of Calgary

The City of Calgary stated that approval of ECI's application at this time would set a precedent and send an improper signal to other prospective cogeneration applicants, which it believes are numerous.

It supported a CPP for future capacity additions to the AIS because an open market driving the price of electricity would bring forth least-cost generation options. Furthermore, a CPP would allow competing proposals to be evaluated on a consistent basis, taking into account all pertinent factors such as cost, reliability, dispatchability, transmission losses, energy efficiency, and environmental factors.

Edmonton Power

Edmonton Power encouraged the Board to conduct a hearing into issues, including CPP, relating to cogeneration projects. The hearing should be initiated as soon as possible and the views of all stakeholders should be obtained.

9.3 Views of the Board

The ERCB is aware that the Provincial Government is currently conducting a review of the regulatory process relating to the electric industry in Alberta. Additionally, electric utilities are looking for efficient and cost-effective ways to secure supplies of electric energy. In particular, utilities are looking at criteria to test the need for new sources, a process to acquire the best generating sources, and alternatives to building new capacity, such as DSM. The Board expects that, within the foreseeable future, a new approach to assessing new generating capacity in the province will be in place.

Because existing surplus capacity in the province is expected to last until the end of the decade, the Board is of the view that it is neither necessary nor appropriate to introduce a new process at this time to deal with new applications. Once the regulatory review is complete a new process may be established by the Board. The Board would invite all stakeholders to participate.

The Board notes that the majority of the interveners are in favour of some kind of competitive market approach for the selection of new generating capacity to satisfy a well demonstrated need. The interveners differ mainly in the areas of who should determine when new capacity is needed, what type of capacity is required to satisfy the need, who should issue requests for proposals, and who should make the selection. The Board is of the view that all these issues, together with any others that may be identified, should be considered when a new process is established.

The Board does not agree with the ACC's suggestion that a "catch 22" situation exists for cogenerators. Should the Board receive applications for approval of new generating capacity before there is a demonstrated need, it may still approve them but, in doing so, it would have to consider, as one of the most important criteria, the effect of those projects on the average cost of generating electric energy in the province. Consideration would also be given to projects that utilize energy sources which are currently being wasted and projects that, because of their geographic location, may be more economic than building transmission facilities. In addition, the Board would consider size, location, costs, construction time, emissions, availability, dispatchability, and flexibility as features of any new generating capacity that it may approve in the future.

Although it is prepared to entertain applications for new generating capacity, the Board does not favor establishment of a queue of approved projects waiting to be built to satisfy a future need. Projects must be justifiable on the basis of need or some other basis such as those discussed above.

10 FINDINGS AND CONCLUSIONS

The Board finds the 1992 EUPC forecast appropriate for determining when the AIS may require new generating capacity. Based on this forecast, current planned retirements of some existing generating units, and taking into account new generating capacity already approved and under construction, additional new capacity may be needed as early as 1997 or as late as 2003. The earlier need, in 1997, is tied to a high load growth scenario forecast based on optimistic economic assumptions. However, the current economic outlook does not support such an optimistic forecast. The Board concludes that need for new capacity is more likely to occur nearer the end of the decade, or even beyond. Therefore, the test of need does not justify approval of new generating capacity at this time.

The Board also finds that approving a power plant that can be constructed in less than 2 years, to satisfy a need expected to occur 5-10 years from now, would be inappropriate, partly because approving it now may preclude more desirable options in the future.

With respect to costs and benefits that may be attributable to the project, the Board finds that most of the benefits to the local community would stem from construction and operation of the greenhouse. However, the project has apparently been designed to maximize the size of the power plant and associated steam generating capability. The Board concludes that the proposal is primarily a power generation venture, the profitability of which is dependent on the price received for the power.

The Board acknowledges that financing for the combined project would be easier if revenue from the power plant were available to support it. However, this benefit must be weighed carefully against the cost of generating electric energy in Alberta. If approval of the proposed plant were to result in improvement to the AIS, in terms of lower costs or enhanced service, any additional benefit associated with the greenhouse would weigh in favour of the plant. If AIS costs are higher, additional benefits would have to be very significant to persuade the Board that the project should go ahead in spite of the extra costs. Indeed, if the greenhouse could not go ahead without the power plant, that in itself would cast a shadow on the combined project, causing the Board to view the proposal even more restrictively as a stand-alone energy project. But, although the applicant argued that the power plant is instrumental in assuring the viability of the greenhouse, cash-flow projections suggest the greenhouse could go ahead on its own.

In considering environmental impacts associated with the proposed plant, the Board finds that only in cases where the proposed plant would displace coal-fired generation would there be fewer emissions. If the proposed plant were to displace gas-fired generation, hydroelectric generation, or imported energy, emissions would be the same or greater. In any event, electric generation by the proposed plant, and its effect on emissions, would be very small relative to total generation in Alberta. The Board concludes that the environmental impact of the proposed plant would be small and, therefore, not a significant factor in its decision to approve or deny the application.

The Board does not accept the applicant's proposal that the output from the power plant should be valued similarly to energy generated by plants under the Program. The proposed plant would not use renewable or waste resources. The applicant's approach to valuing the output from its proposed plant would result in the overall cost of generating electricity being significantly higher than if the energy were generated by existing capacity on the AIS. Based on a cost of 3.95 cents per kW•h, the Board estimates that this increase in cost would approximate $ 6 million per year during the period the AIS does not require additional capacity.

In summary, the Board concludes that:

- although need for additional capacity by the AIS may occur as early as 1997, the current economic outlook suggests it is more likely to occur nearer the end of the decade,

- given a construction period of 2 years, it would be premature to approve the power plant now. Approval now may preclude consideration of other viable options which may be available to meet the need for new capacity,

- the method proposed to determine the value of the output of the power plant would result in the cost of that output exceeding the existing system's incremental cost of generation,

- the proposed greenhouse could bring benefit to the local community and, on the evidence submitted, appears to be viable without the power plant,

- benefits attributable to the power plant are not sufficient to offset the extra cost to the AIS that may have to be borne by all electric consumers in Alberta, and

- operation of the proposed power plant would not have a significant positive or negative effect on emissions and air quality in Alberta.

11 DECISION

Having regard for its responsibilities under the Hydro and Electric Energy Act, the Board concludes that construction and installation of the applied-for power plant at this time would not be consistent with the objectives of economic, orderly, and efficient development and operation of the Alberta electric system. Accordingly, the Board denies the application.

DATED at Calgary, Alberta, on 26 February 1993.

ENERGY RESOURCES CONSERVATION BOARD

J. P. Prince

J. P. Prince, Ph.D.
Vice Chairman

R G Evans

R. G. Evans, P.Eng.
Board Member

A. C. Barfett
Acting Board Member

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Energy Consulting Inc. (ECI) A. Milne	Dr. Colin Jackson E. Travis R. Stewart T. Henry
Town of Stettler (Town) C. Newton	C. Newton
Stettler Economic Development Board (Development Board) Mrs. C. Jackson	Mrs. C. Jackson
County of Stettler No. 6 (County) R. Hennel	R. Hennel
Downtown Merchants' Association of Stettler (Merchants' Association) W. Stratulate	W. Stratulate
Stettler & District Chamber of Commerce (Chamber of Commerce) N. Connor	N. Connor
Electric Utility Planning Council (EUPC) F. A. Day	R. Belland J. Worsick
Alberta Federation of Rural Electrification Associations (Federation of REAs) K. Sisson	H. Schwenk
Industrial Power Consumers Association of Alberta (IPCAA) D. E. Crowther	M. Drazen R. W. Gallant M. K. Smith
Alberta Cogenerators Council (ACC) A. O. Ackroyd, Q.C.	K. Logan
City of Calgary R. F. Goss	
City of Edmonton (Edmonton Power) D. M. Tadman	

TABLE 1 THOSE WHO APPEARED AT THE HEARING (cont.)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Alberta Power Limited (Alberta Power) D. O. Sabey, Q.C.	J. R. Frey, P.Eng. G. Lake, P.Eng. B. Laing, P.Eng. J. Walker, P.Eng.
TransAlta Utilities Corporation (TransAlta) T. Dalgleish	J. A. Tapics, P.Eng. R. W. Way, P.Eng. B. T. Laxdal, P.Eng.
R. M. Somerville	R. M. Somerville
D. Wozney	D. Wozney
Mr. Dodds	Mr. Dodds
Energy Resources Conservation Board staff M. Asgar-Deen, P.Eng. P. Wickel, P.Eng. K. Gladwyn J. Wilson, P.Eng. C.J.C. Page	

APPENDIX A
TERMS AND DEFINITIONS

Alberta Interconnected System (AIS)

Power plants and electrical loads that are connected by a continuous transmission system, and therefore, operating in synchronism. The majority of the provincial system is interconnected.

Carbon Dioxide (CO_2)

Gas produced by most combustion processes such as the burning of fossil fuels. It is also produced by animal bodies and expelled out from the lungs.

Cogeneration

The simultaneous production of electrical or mechanical energy and thermal energy from the same fuel source. Cogeneration is commonly used by commercial or industrial processes that require both electrical power and heat.

Competitive Procurement Process (CPP)

A process whereby an electric utility obtains electric energy and capacity from the market place on the basis of a competitive bidding system.

Decibel (dB)

A unit of measure of sound pressure.

Demand Side Management (DSM)

The planning and implementation of those utility activities designed to influence customer use of electricity in ways that will promote desired changes in the utility's load shape, i.e. changes in the time pattern and magnitude of a utility's load.

Gigajoule (GJ)

One billion (10^9) Joules (see Joule).

Gigawatt Hour (GW•h)

One billion (10^9) Watt hours (see Watt hour).

Joule

Work done by a force of 1 Newton acting through a distance of 1 metre.

Kilovolt (kV)

1000 Volts (see Volt).

Kilowatt (kW)

1000 Watts (see Watt). It is equivalent to approximately 1 1/3 horsepower.

Kilowatt Hour (kW•h)

1000 Watt hours (see Watt hour). Commercial unit of electric energy.

Megawatt (MW)

One million Watts (see Watt).

Nitrogen Oxides (NO_x)

By-product of some combustion processes. It is produced when nitrogen gas contained in the atmosphere and in the fuel chemically combines with oxygen during high temperature combustion.

Potential Load Served by Self-generation (PLSS)

Electric load supplied by some utility customers who may generate to satisfy their own electric needs. This should be distinguished from non-utility projects which generate primarily for sale to utilities.

Parts Per Million by Volume (PPMV)

Unit of measurement of air pollution in atmospheric gases. It represents the concentration of air pollutants as a number of parts of pollution in one million parts of volume.

Sulphur Dioxide (SO_2)

By-product of some combustion processes. It is produced when sulphur contained in the fuel combines with oxygen during high temperature combustion.

Utility Sponsored Energy Efficiency Programs (USEEP)

Programs implemented by utilities to encourage their customers to make wise and efficient use of electric energy.

Volt

Measure of electric potential or electromotive force.

Watt

Power that produces energy at the rate of 1 Joule per second.

Watt Hour

Amount of power generated or consumed over a period of one hour.

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